

COMMENTS OF DIRECT ENERGY SERVICES, LLC ON

HOUSE BILL 5505 – AN ACT CONCERNING ELECTRIC RATE RELIEF

HOUSE BILL 5507 – AN ACT CONCERNING CONSUMER PROTECTIONS IN THE ELECTRICITY MARKET

HOUSE BILL 5508 – AN ACT ESTABLISHING THE DIVISION OF ELECTRICITY POLICY AND PROCUREMENT

Direct Energy Services, LLC (“Direct Energy”) submits these comments opposing House Bill 5505, An Act Concerning Electric Rate Relief. Direct Energy is a licensed electricity and natural gas supplier in Connecticut and, along with its affiliate, Direct Energy Business, LLC, serves approximately 90,000 residential and business customers in the State.

General Comments: Connecticut Does Not Need a Risky and

Radical Re-Shaping of Its Electricity Markets

HB 5505 contains a large number of measures that, when taken together, would radically change the electricity market in Connecticut. A handful of these measures (most notably efforts to provide assistance to low-income customers and to provide greater consumer protection) show some promise from a policy perspective. The majority of the provisions in this bill, however, will harm Connecticut consumers and businesses, limiting their choices in meeting their energy needs, driving up costs through the creation of new governmental agencies, and risking billions of dollars of taxpayer and ratepayer funds in a misguided attempt to wrest control of the electricity markets away from consumers (where it resides now) and place it in the hands of a small group of utility executives and bureaucrats.

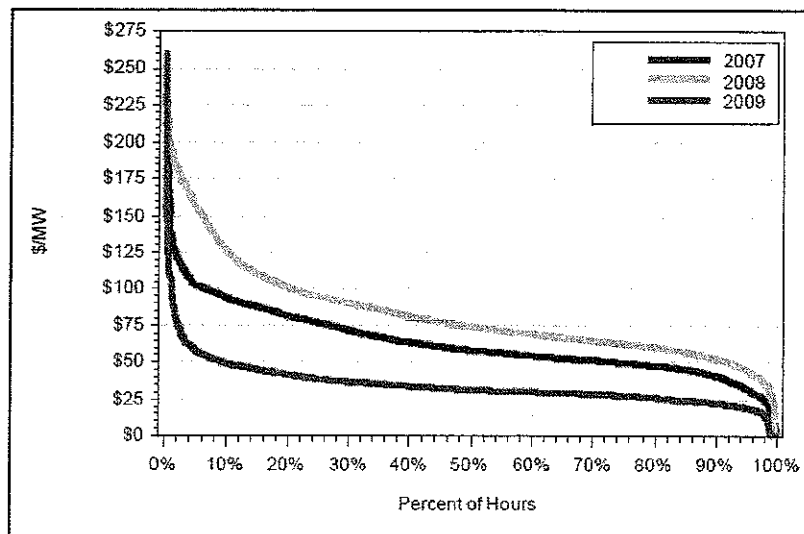
The riskiest and most fiscally dangerous provisions of the bill are those that would (1) create a state power authority (the Connecticut Energy Authority, or “CEA”), (2) allow utilities to procure power for standard service customers (those with annual peak demand below 500 kilowatts), and (3) hold standard service customers captive to the utility for two years unless they pay a fee to switch. These provisions appear to rest upon the two premises that past attempts at similar changes have rested upon, namely that electric restructuring has failed to control prices and that utility executives and government agencies would be able to lower electricity costs where markets have not. These premises are at odds with the reality of what has happened in the Connecticut electricity market over the past several years.

To maintain the premise that restructuring has failed, one must ignore the trend of wholesale prices in New England and also incorrectly attribute any disconnect between wholesale and retail prices to restructuring rather than to other factors, which turn out to be the actions of the very utilities and governmental agencies that the bill would give near-total control of Connecticut’s electricity market over to.

Wholesale Prices Have Responded Appropriately to Market Forces

As expected in a system that uses competitive forces to control prices, wholesale electricity prices have plummeted in New England and across the United States, as demand has weakened and input fuel prices have dropped due to a number of factors. The latest quarterly report from ISO-NE, for the third quarter of 2009, shows how striking these price reductions have been (see Figure 3-12, below). In Q3 of 2007, the hourly real-time system price exceeded \$50/MWh in about 80 percent of the hours in that quarter. In Q3 of 2008, prices exceeded \$50/MWh in more than 90 percent of the hours. In Q3 of 2009, prices exceeded \$50/MWh in **only 10 percent of the hours**.

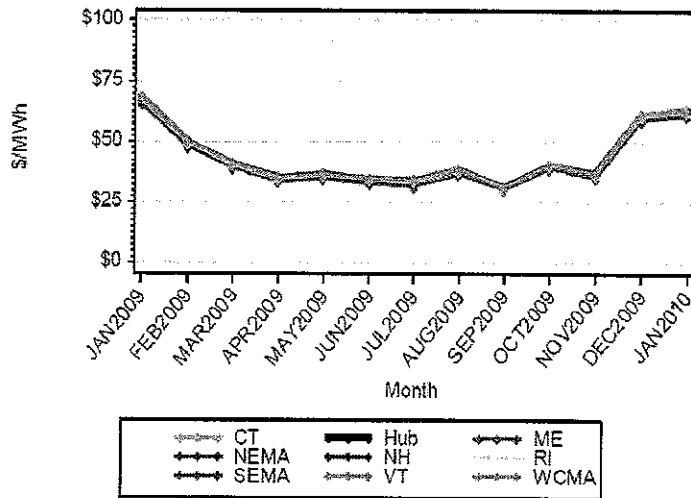
Figure 3-12 New England Hourly RT System Price Duration Curves
2007-2009, Q3 Prices < \$275



Note: Real-time prices exceeded \$275/MWh during three hours in Q3 2007, one hour in Q3 2008 and no hours in Q3 2009.

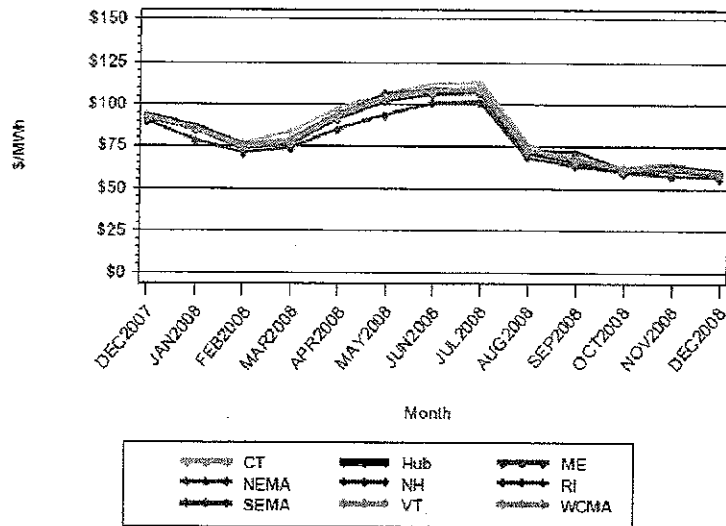
The overall trend in wholesale prices has also moderated considerably. In the 13 months ending January 2010, monthly average real-time wholesale prices ranged from about \$30/MWh to 70/MWh.

Monthly Avg Real-Time LMPs for Hub and Load Zones
13 Mos Ending January 2010, All Hours



In the 13 months ending December 2008, monthly average real-time wholesale prices ranged from about \$60/MWh to \$110/MWh.

Monthly Avg Real-Time LMPs for Hub and Load Zones
13 Mos Ending December 2008, All Hours



This phenomenon is not limited to the New England wholesale markets. The PJM Interconnection and the New York ISO have also shown similar decreases in average prices. The NYISO recently reported its lowest wholesale prices in its 10-year history. The average wholesale price in that market in 2009 was \$48.63/MWh, 49 percent below the 2008 average of \$95.31/MWh, and lower than the previous low of \$49.90 in 2002. Wholesale prices in PJM averaged \$39.05/MWh in 2009, the lowest they have been since 2002 and a 45 percent drop from 2008.

In the face of this evidence, proponents of HB 5505 might claim that while prices may have come off recently, they will soon begin an inevitable and inexorable upward climb. This pessimism finds little support in the real world. In fact, there are powerful forces that are in the process of changing the long-range dynamics of the New England energy markets that could not be imagined just a few years ago. These forces include the unexpected impacts of the financial crisis and ensuing recession, which has been longer and more severe than any since the Great Depression, an increasing region-wide focus on energy efficiency, conservation and demand response, and material developments in the market for input fuels, especially natural gas.

The most recent Integrated Resource Plan, prepared jointly by Connecticut Light and Power and United Illuminating for submission to the Connecticut Energy Advisory Board, described this trend in natural gas prices in dramatic terms:

Recent developments suggest that the long term outlook for natural gas in New England is positive. There has been a dramatic improvement in the outlook for long-term U.S. natural gas supply and price in the last year, driven primarily by increasing “unconventional gas” production and reserves – mostly shale gas, but also coal bed methane and other “tight” gas formations. These unconventional sources have been called a “game changer” and the “biggest energy innovation of the decade” that could “transform the debate over generating electricity.” Analysts have forecast that the major shale gas plays can cover their break-even costs for around \$4.00/MMBtu. Of particular interest to the Northeast is the Marcellus Shale, due to the magnitude of the supply potential, its expected low cost and its nearby Appalachian location. Additional supplies are coming via new pipeline capacity from the Rocky Mountains and from new LNG terminals, and additional infrastructure is being developed to deliver these supplies into New England. Both short-term and long-term gas prices have declined markedly. While this new potential supply, particularly shale gas, has yet to be fully realized, and factors could yet hinder its development, the outlook for natural gas supply for power generation in New England is significantly improved compared to even just a few years ago.

2010 Integrated Resource Plan at 9-2 (footnotes omitted).

As a result of these new sources of natural gas, the IRP’s “Key Findings” for natural gas prices in New England are encouraging. This is especially important for Connecticut and New England power prices generally because natural gas is the fuel that sets the price in approximately 60 percent of the hours in the ISO-NE wholesale energy market.

- The overall supply picture for domestic natural gas appears promising, due particularly to the advent of new unconventional gas supplies such as shale gas. This expanding supply should be adequate to accommodate even increased gas demand, though the ultimate extent and pace of the new supplies coming online is not certain.
- Pipeline and LNG delivery capacity to New England have increased over the past several years, with additional new expansion projects still in development for the near future. Gas delivery capacity to serve average and peak needs has improved measurably from a

few years ago (though this does not address gas local distribution company (LDC) deliverability issues, where additional expansions may be necessary).

- LNG and Canadian conventional gas may be less important for augmenting New England gas supplies than was expected in the recent past, due to the advent of new domestic supplies at lower prices. They will nonetheless continue to serve as a backstop for the availability and price of domestic gas supplies. Regardless of whether it actually does substitute for domestic gas more widely, LNG will remain a crucial component of New England's ability to meet peak gas demands in the winter heating season.
- Natural gas prices are expected to remain reasonable at around \$7.00/MMBtu (real dollars) in the long term, driven largely by new unconventional supply sources. However there is no certainty that these current price expectations will be fulfilled; a long-term gas price range of approximately \$4-10/MMBtu was examined in this study. Regardless of what happens to the long-term price of gas, short-term gas prices can be volatile.

2010 Integrated Resource Plan at 9-3.

In short, the wholesale power markets have responded as one would expect to decreases in input fuel prices, especially for natural gas, delivering lower prices across the region, including in Connecticut. Given the long-term outlook for natural gas prices described in the IRP, and other factors such as an emphasis on energy efficiency, conservation and demand response, there is also reason to be optimistic that a long run-up in power prices can be avoided without engaging in risky, unproven and radical alterations to Connecticut's energy markets.

The Retail Market Is Delivering Extraordinary Value to Customers

Against this backdrop, as would also be expected in a period of moderating wholesale prices, the retail market is delivering value to hundreds of thousands of Connecticut businesses and consumers. Based on the latest available migration statistics (January 2010 for CL&P and February 2010 for UI), competitive suppliers now serve just under 20 percent (19.6 percent) of all of the customers in Connecticut, accounting for nearly 50 percent (49.6 percent) of all of the load in the State. Among the largest customers, who are eligible for last resort service from their utility, which is procured on a quarterly basis and thus reflects more current market prices, the migration level is extraordinary. Eighty-four percent of those customers, who represent most of the largest employers in the state, are on competitive supply, accounting for more than 90 percent of the load in that sector.

In the standard service sectors, which include residential customers and businesses with annual peak load less than 500 kW, the move to the competitive market has also been striking. Before 2007, these sectors showed little interest in the competitive market, a factor that was often cited as a justification for efforts to re-monopolize service to those customers, either with the utility or a public power authority. Those customer segments have shown an explosion in shopping, with the number of residential customers taking advantage of competitive offers having increased by

more than 100 percent in 2009 in both utility service territories. Nearly 17 percent (16.9 percent) of all residential customers in the state, accounting for 19 percent of the load in that sector, are now with a competitive supplier. Small and medium businesses, which are widely recognized as the job-creation engine in the economy, have also moved to take advantage of the options and value provided by the competitive market. Forty-two percent of those customers, accounting for 67 percent of the load in that sector, are on competitive supply.

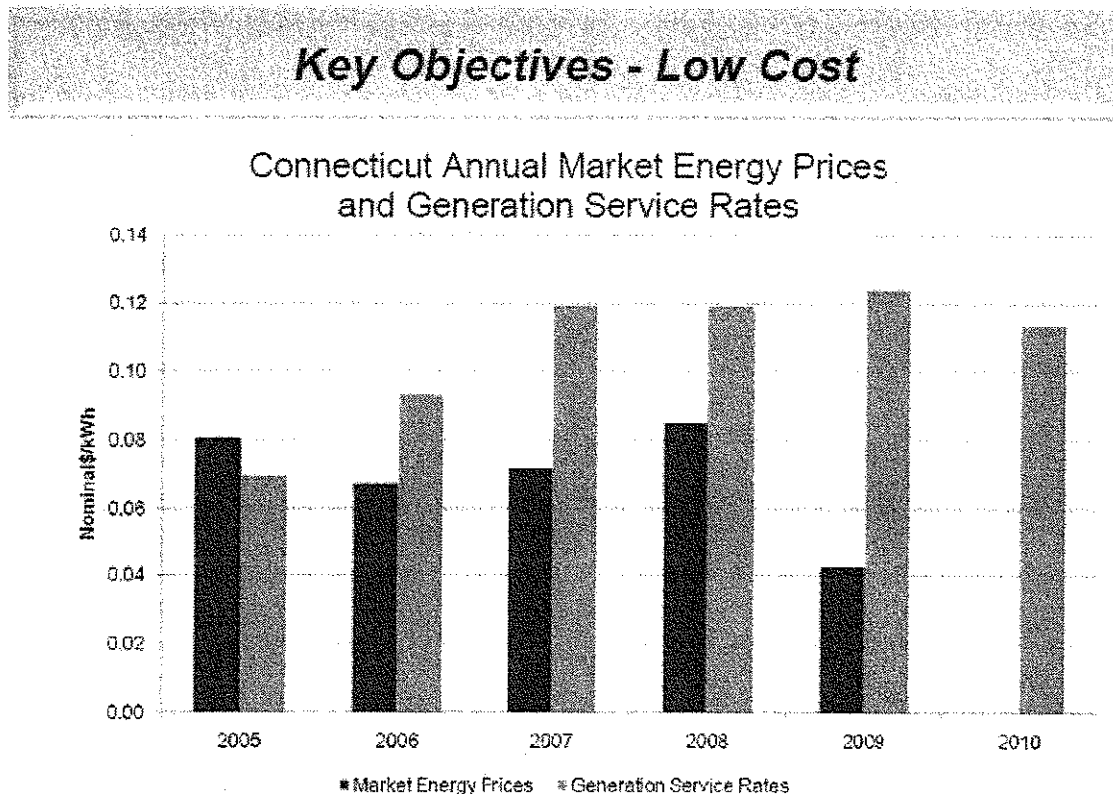
Because the standard service sectors are the focus of the most radical parts of HB 5505, those customers warrant further consideration. The main reason those customers are shopping in such large numbers is obvious from even a cursory glance at the available offers on www.ctenergyinfo.com: customers can save money versus the standard service price by switching to a competitive suppliers. Currently, every one of the 21 offers listed for the CL&P service territory is below the standard service price. In the UI service territory, 19 of 20 offers is below the standard price. (The 20th, which is a Direct Energy offer, is a time-of-use product in which the on-peak price is above the standard service price and the off-peak price is below.) Direct Energy has estimated that its customers saved nearly \$6 million versus the standard service price in 2009.

The value available in the competitive market is usually ignored by those who cite Connecticut's high electricity prices, especially in the standard service sectors. In fact, competitive options have offered residential and business customers alike an important alternative to standard service as wholesale market prices have gone down while standard service prices remain relatively high. But even more egregious than their dismissal of the availability of competitive supply options by proponents of such radical measures as are contained in HB 5505 is their mischaracterization of the reasons for those standard service prices. The usual narrative is that Connecticut's high prices have been caused by "deregulation." While Direct Energy emphatically rejects this view, one need not engage that particular debate in order to identify the major and unequivocal reason behind the persistence of standard service prices above current market prices: the utility procurement process, which has emphasized "price stability" over sending timely price signals, results in a standard service price that lags the market so that prices are relatively high when the wholesale market is down.

The utility standard service procurements plans that were modified and approved by the DPUC in 2006 resulted in procurements that are highly "laddered." That is, much of the supply for standard offer was purchased in 2007 and 2008, on two- or three-year contracts, when market prices were high. (The remainder was procured in 2009, when wholesale prices were on the way down.) This approach, which was generally supported by parties such as the utilities, the Office of Consumer Counsel, and the Attorney General, was vigorously opposed by the competitive suppliers, represented by the Retail Energy Supply Association ("RESA"), of which Direct Energy is a member. RESA recommended instead that standard service be procured through

overlapping contracts of no greater than six months duration. If those recommendations had been adopted, standard service prices would be much lower now, reflecting the lower current wholesale prices.

This disconnect between utility generation prices and wholesale prices was illustrated in the IRP, which showed utility generation service rates rising in 2009 to nearly three times the average wholesale price (see slide below). While the retail generation price will always be higher than the average wholesale price, due to the need to acquire the other elements of all requirements service and to shape the supply to customers' actual consumption, there is little question that the overall approach to utility procurement for standard service, with its heavy reliance on two- and three-year contracts, has kept prices high even as market prices have dropped. This is especially problematical when much of the reduction in wholesale prices has been caused by reduced demand due to a severe recession. Utility generation prices remain high at a time when residential and small business customers most need them to reflect current market conditions.



In these conditions, competitive supply has been a tremendous benefit for consumers and businesses which otherwise would have been trapped on higher priced utility service. Rather than acknowledge this benefit, the proponents of HB 5505 continue to push for radical changes to the electric markets where simple changes to the utility procurement approach would achieve

far better results at essentially no cost. That simple solution is to adopt RESA's recommended approach to standard service procurement from 2006, with contracts not to exceed six months, which could be done by the DPUC under the existing statutory authority. Better still, the Legislature could direct the DPUC to use quarterly procurements, as is done now for last resort service, with some staggering of contracts to avoid all of the supply for both standard service and last resort service being procured at once. This change would better align retail and wholesale prices, providing clearer incentives for energy efficiency and demand response, and rid the system of the many ills that come from having the price for utility generation service lag the market. The apparent presumption that underpinned this approach, namely that prices would only go up, making buying forward a winning long-term strategy, has been conclusively disproven by the events of the past two years. Connecticut should not rely on the same mistaken assumptions now to make extremely risky changes to the electric markets that could prove to be a financial disaster for the State.

Comments on Specific Sections and Proposals

Sections 7 and 9 –Connecticut Electric Authority (“CEA”) and Utility Generation

Section 7 of the bill would create the CEA, which “may own and operate electric power plants and may provide financial assistance ... to encourage the development of” generation.” Section 9 would allow the Authority to “order an electric distribution company to submit a proposal ... to build” generation. The CEA would also take over much of the authority that is currently vested in the DPUC for conducting and reviewing power procurements for standard service.

Proponents of HB 5505 continue to pursue a state power authority as a “magic bullet” for Connecticut's high prices. Some even suggested last year that a power authority could save Connecticut consumers 20 percent on generation, with a budget of less than a million dollars. These claims are unsubstantiated and irresponsible. The idea that a public entity would be able not only do better than any wholesale or retail supplier but to do so by a wide margin with a minimal investment is fantasy. The only thing that one can know for sure about a public power authority is that it will impose costs on ratepayers and/or taxpayers that are not being imposed now, while exposing them to risks they are not currently exposed to.

There are only a handful of scenarios for the manner in which the CEA might operate, each of which has its own costs and risks. The CEA could do nothing more than what the utilities and the DPUC are doing now, that is, supervise, review and approve procurements for standard service under that same approach currently taken by the utilities. There is no evidence that the utilities and the DPUC are incapable of performing these functions in a perfectly adequate manner today. The only thing the CEA would be able to do is to create a duplicative governmental entity with staff and expenses that would be incremental to the DPUC's current staff and expenses.

It is unlikely that the proponents of HB 5505 had in mind that the CEA would do anything so limited as simply take over the role currently served by the DPUC with respect to standard service procurement. The bill allows far greater involvement in Connecticut's electricity markets, up to and including owning and operating power plants or providing financial assistance to encourage the development of generation. Any such activities would be crushingly expensive for the State, and are so inherently risky that to undertake them would expose the State to potentially disastrous financial consequences.

The planning and construction of even a small power plants involves an investment of hundreds of millions of dollars, which the CEA would raise by issuing bonds. The bill provides that the debt service on these bonds would be paid by pledging the revenue associated with the operation of a power plant built by the authority. This scheme, of course, presumes that the plant is able to be built and operated in a sufficiently efficient manner that it produces enough revenue to cover all of its operating expenses and the debt service, which is not a foregone conclusion. If there is any shortfall in the various accounts that would be created for the purpose of operating the plant and paying bond holders, these obligations would be backstopped by the general fund, meaning tax payers would be on the hook. Construction delays or cost overruns, which under the current system would be the responsibility of the investors in the merchant generator building the plant, could easily be imposing costs on taxpayers before the plant generated a single kilowatt-hour of electricity. Once the plant is built, unplanned outages or other unforeseen developments in the generating market would also present challenges to financially successful operation of the plant, further exposing taxpayers to risk they are immune to today. (The fact that the CEA could pursue plant construction and operation by ordering the utilities to do so rather than doing so on their own does not change the equation; it simply substitutes "ratepayers" for "taxpayers," as it is clear the utilities could not be forced to build or operate plants at shareholder expense.)

A state power authority has been a bad idea from the beginning, but it appears to have had its genesis at a time when Connecticut was projected to be short on power, especially in the constrained Southwest Connecticut region. While being, in our view, bad public policy, the view at the time that some entity needed to stand ready to build facilities that might be required to keep the lights on in the absence of private development was not completely irrational. But Connecticut has moved on from those times. With nearly all of the measures prescribed by the Legislature in P.A. 05-1 and P.A. 07-242 now having been implemented, along with ongoing transmission upgrades and expansions and the continued penetration of energy efficiency and demand response, Connecticut finds itself fairly flush with resources. The IRP's examination of and conclusions regarding resource adequacy describe this situation in no uncertain terms.

1. Resource Adequacy

- There will likely be a substantial surplus relative to Connecticut's local resource requirements through 2020, due to a lower load forecast than utilized in prior IRPs,

planned generation additions in Connecticut, planned DSM, and increased Connecticut import capability, even after accounting for forecasted retirements (which are substantial). Given this, Connecticut's access to adequate resources depends on resource adequacy in New England as a whole.

- A capacity surplus is expected in New England through at least 2015, and likely through 2020. This region-wide surplus is due to a lower load forecast than in prior IRPs, the likely addition of renewable generation to meet RPS requirements, planned DSM, and planned generation additions in Connecticut even after accounting for forecasted retirements (which are substantial). Some combinations of strategies and scenarios may lead to a need for additional resources after 2015 in cases that involve higher load, lower renewable additions, and/or higher retirements.
- The prospect of capacity surpluses and consequently low capacity prices, combined with tighter environmental requirements, is likely to induce the retirement of substantial amounts of old, high emission, oil-fired steam units. Retirements are estimated at 2,446 MW in New England in the Base Case (1,504 MW in Connecticut). There is substantial uncertainty around these estimates; retirements could exceed 4,000 MW under market conditions that induce earlier new entry and reduced capacity prices.

Given the projected surpluses of capacity in the region, whatever justification there may ever have been for a power authority in the eyes of its proponents has vanished. Connecticut has achieved a level of resource adequacy that few would have thought possible five years ago, and it has done so without the kind of radical and risky intervention in the market that the CEA would represent.

Section 17 – Utility Managed Portfolio for Standard Service

This section would require utilities to file plans that would transition standard service procurement away from the full requirements requests for proposals used today to having the utilities manage a portfolio of supply components to meet standard service load by 2013. As with the CEA, this change would expose ratepayers to significant risks they currently avoid. These risks could potentially threaten the overall health of the state's investor-owned utilities and drive up not only generation rates but also rates for the delivery services that are the utilities' core function. The change would also severely hamper the competitive market and deprive the procurement system of the relative transparency it enjoys today.

What the proponents of HB 5505 of ignore is the extraordinary amount of credit and collateral that an entity that engages in the kind of "managed portfolio" envisioned must incur. With the current all-requirements procurement approach, the utility avoids most of these costs. But a utility that enters into the kind of arrangements required by Section 17 would incur costs that could place a tremendous burden on ratepayers. Entering into bilateral agreements directly with generators, for example, would require the utility to post collateral that would change with the relationship between the contract price and the market price (the so-called "mark to market" risk). The longer the commitment, the greater the credit support required, and the greater the

likelihood that changes in the market could expose the utility to a potentially catastrophic increase in collateral requirements. These would occur where the market price falls well below the contract price. In that case, the entity paying the above-market price (here, the utility) would be required to post additional collateral commensurate with the default risk associated with being the buyer of power that is well above market. These very circumstances could have occurred if the utilities had been allowed to pursue this course in 2007, when some were suggesting that they be given a mandate similar to the one contained now in Section 17 of this bill. If that had happened, a utility that was the counter-party to such an above-market contract would have to post additional collateral in the form of cash or cash equivalents, placing immediate financial stress on the utility and its ongoing operations.

The opposite scenario, in which the contract price proves to be much lower than the market price, would appear to be quite advantageous to the utility and its ratepayers. But some deals can be too good. A wholesale supplier that is far "out of the money" would itself have to post collateral commensurate with its risk of default, which increases as the market price rises above the contract price. Inability to produce sufficient collateral could itself produce a default, leaving the utility and its ratepayers exposed to the market price at a time when, by definition, it has increased above where it was at the time the contract was signed.

Proponents of a managed portfolio by the utility, who sometimes speak cavalierly about long-term deals of 10, 15, or 20 years duration, are either ignorant of or simply ignore these risks. As has been amply demonstrated by the swings in the power market over the past 10 years, the odds that at some point in a 10 to 20 year period short-term volatility will be high enough to cause large and potentially catastrophic swings in collateral requirements are substantial. These risks are best avoided by an entity such as the utility, which has core functions that depend on ready access to the cash the company generates through its revenues. There is no need to risk having those revenues re-directed to the credit and collateral requirements that a managed portfolio would entail.

A managed portfolio approach would also bring about a decided reduction in transparency and accountability compared to the current all-requirements approach to standard service. This poses three risks to Connecticut consumers and businesses. First, without the relative discipline imposed by the current approach, which uses all-requirements contracts that involve little risk to ratepayers, utilities could make significant risky investments that could be reviewed and approved without the kind of scrutiny that would expose the true nature of the risks involved. In past proceedings, utilities have suggested that risky bilateral contracts might be approved so long as the contract price is lower than the forward price for power at the time the contract is reviewed. This would be a recipe for stranded costs, as recent events have reminded us all that prices can go down as well as up.

Second, managing a complex portfolio of generation assets to serve standard service would present temptations to push current costs off to the future through deferrals and reconciliations. These temptations would arise where including all of the current costs would put the standard service price at a competitive disadvantage against offers from suppliers, raising the possibility of revenue insufficient to recover all of the utility's costs. Such deferrals distort the competitive market and also put future ratepayers at even greater risk of stranded costs as utilities might eventually be unable to recover all of their generation costs from standard service customers.

Finally, utilities using a managed portfolio have a strong incentive to move generation-related costs to delivery rates wherever possible, which serves the dual purposes of increasing the number of customers from who the costs are recovered and improving the competitive position of the utility service versus non-utility suppliers. One Connecticut utility has already sought an explicit shifting of generation costs from its generation services customers to all customers. In their oral testimony in support of HB 5365, which allows utilities to invest in renewable resources and to recover their costs through a non-bypassable charge, United Illuminating's witness testified that the utility would use the renewable energy credits created by any such renewable assets to meet its renewable portfolio standard obligations. Renewable portfolio obligations are an element of retail service. Allowing a utility to recover some or all of its RPS costs through a non-bypassable charge would force customers of competitive suppliers to subsidize the RPS costs of utility customers while paying their own share through their competitive supplier's charges.

The other Connecticut utility has demonstrated the risk to ratepayers and customers of electric suppliers from allowing utilities to pursue a "managed" portfolio. Connecticut Light and Power frequently cites the experience of its affiliate, Public Service of New Hampshire ("PSNH") as evidence that a managed portfolio can bring better prices. The past two years have shown that this claim is a gross exaggeration, as PSNH pursued forward power purchases that left it dangerously exposed to the dual risk that prices might go down (which they did) and that, in response, customers would migrate away from utility supply for less expensive competitive options (which they did). In fact, it appears that one reason CL&P is likely to support efforts to curtail customer choice, in conjunction with its efforts to introduce a "managed portfolio" approach to standard service, is that Northeast Utilities has been unable to identify an effective strategy for dealing with migration to competitive supply.

For example, in building its portfolio of resources to serve its default service customers in 2010, PSNH spent \$97 million at an average price of \$93/MWH but, due to high levels of customer migration, would be forced to sell about a third of that amount as "Surplus Energy Sales" at an average price of \$43/MWH. (See attached testimony of Michael Hachey of TransCanada Power Marketing Ltd., in Docket DE 09-180 before the New Hampshire Public Utilities Commission ("Hachey Testimony"), at 6.) It appeared that PSNH had not followed its own plan in hedging

against the possibility of customers migration, although ascertaining exactly what PSNH might or might not have done was made more difficult by the lack of transparency in those activities (Hachey Testimony at 6-7). In response to this customer migration (which had reached 23 percent of load as of late 2009), PSNH proposed to do just what suppliers fear the Connecticut utilities would do in similar circumstances: pass costs incurred to serve utility default service customers on to all customers, including those on competitive supply (Hachey Testimony at 8-9).

This episode illustrates three broad concerns Direct Energy and other suppliers have about allowing utilities too much discretion in managing a portfolio of resources to serve standard service load rather than continuing to rely on all-requirements contracts as they do today. First, if allowed to do so, utilities are as prone as any other entity to make mistakes in betting on the direction the market will take. This is apparently what PSNH did with its 2008 power purchases. Rather than using the more conservative strategy outlined in its own Integrated Resource Planning document, PSNH made purchases in 2008 on the assumption (now exposed as little more than a gamble) that power prices would continue to rise, without limitation by the demand response that would typically be seen in such circumstances (Hachey Testimony at 10). Second, where a utility does make a mistake in managing its portfolio, it will seek to recover excess generation costs from all customers, including customers of competitive suppliers, introducing inefficiencies and distortions in the market in order to cover their bad decisions. Finally, the PSNH experience shows that it is very difficult for a utility commission and other market participants to adequately monitor the activities of a utility that is granted a high degree of discretion in making power purchases other than through all-requirements agreements at regular intervals. The New Hampshire PUC has an experienced and capable staff, but no utility commission or market competitor can match the utility in its intimate knowledge of its own processes when allowed to use the kinds of options described in Section 17 of HB 5505. A regulator or other party can only attempt to discover what may have happened after the fact, when it may be too late.

Section 29 (Contract Rescission, Supplier-Customer Meetings): Section 29 would allow commercial and industrial customers of all sizes to rescind a contract with a competitive electric supplier within three business days, a rule that currently applies only to residential and small commercial customers in the standard service class. Section 29 also limits customer meetings (including pre-scheduled meetings at the customer's place of business) to between the hours of 10:00 a.m. and 6:00 p.m. and requires virtually all customer meetings to have a predetermined script.

Direct Energy strongly supports incremental consumer protection measures for the Connecticut market, and supports some of the measures set forth in HB 5505. Some of the proposals in Section 29, however, appear designed only to hinder the already robust commercial and industrial market, driving up costs with no corresponding benefit whatsoever. Forcing large

commercial and industrial customers to accept a three-day right of rescission will simply drive up costs. Pricing decisions for such customers are typically made in a matter of hours, as competitors vie to provide the most attractive price then available, with the understanding that once a customer commits to a particular supplier, that supplier will lock in (or hedge sufficient supply to serve the customer at the agreed-upon price. Such deals are also backed by extensive customer agreements that have typically been negotiated in advance, with a careful allocation of risks between parties of equal bargaining power. Imposing a non-waivable three-day rescission period on top of this existing system (which currently supports a migration level of greater than 90 percent in this customer sector) will introduce a degree of uncertainty to each transaction that will hamstring the ability of competitive suppliers to make timely and aggressive price commitments. This would result directly in higher costs for this customer segment, many of whom represent some of the largest employers in the State. This provision is bad for everyone involved and should be rejected.

Regarding the other provisions of Section 29, Direct Energy is generally supportive, but would encourage modifications to the provisions to give the DPUC authority to address incremental consumer protections. The provisions in Section 29 are too prescriptive and appear to be based more on speculation about what customers want and how they interact with sales agents than on actual experience or empirical. In our view, the DPUC is well-equipped to use a general grant of discretion to promulgate a set of consumer regulations and guidelines that would adequately protect customers while not overly burdening the marketing process and unnecessarily driving up costs. Direct Energy also views such incremental measures as most appropriate for residential and the smallest commercial customers, perhaps those under 50 kW in annual peak demand. Commercial, industrial and institutional customers of greater size are increasingly sophisticated in their dealings with energy marketers, especially where they make use of aggregation programs run by organizations such as CBIA or MAC. In our experience, competition for these customers is robust, and firms that do a poor job of explaining who they are and what they are selling will be punished in the marketplace, without incremental regulations that might have the unintended consequence of driving up prices available from suppliers.

Section 30 (Customer Switching Restrictions, Exit Fees): Section 30 appears to impose a two-year minimum stay requirement on standard service, unless one pays a fee to the utility in order to switch to a competitive supplier. This provision is a blatant attempt to restrict customer choice for no reason other than to enable some of the radical revisions to the Connecticut electric market discussed above. Considering that current offers from competitive suppliers are well below the standard service price, this provision amounts to a de facto rate hike for customers who otherwise would switch but for the exit fee this section would impose. Connecticut consumers and businesses need more options, not rate increases masquerading as rate relief.